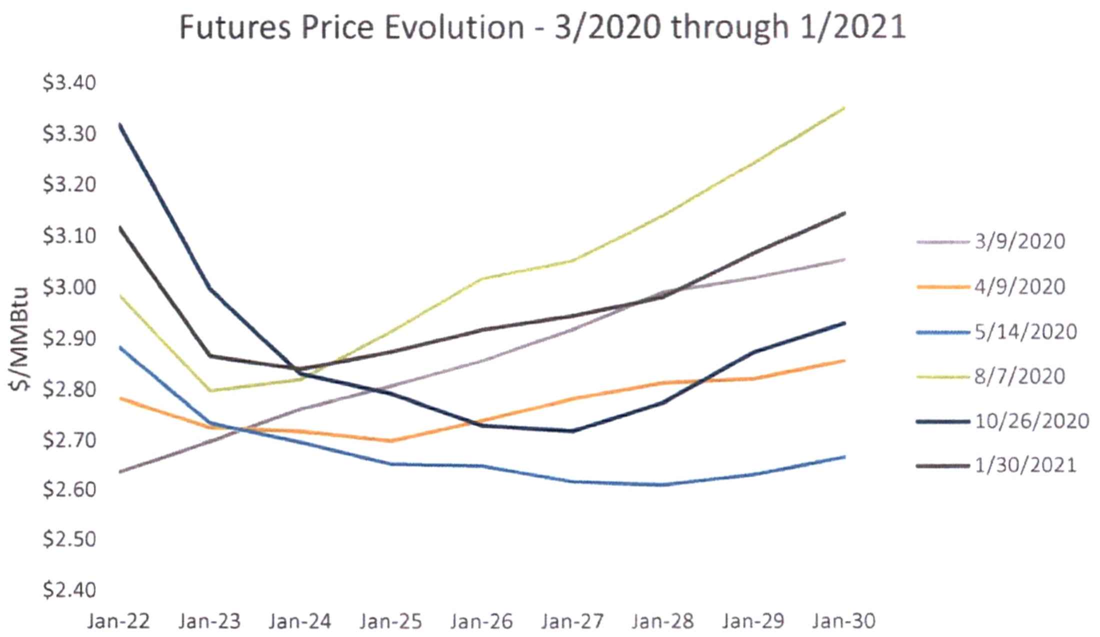

Figure 5 - Futures Price Evolution - 3/2020 through 1/2021

To combat this volatility, I reiterate my recommendation to use the average of daily NYMEX prices for the month prior to the beginning of the forecast period and relying on them for only 18 months before transitioning to the average of at least two fundamentals-based forecasts over the following 18 months. This approach maximizes the useful information in short-term futures prices while avoiding basing long-term prices on illiquid prices that underlie OTC swaps.

Q33. MR. SNIDER CLAIMS THAT YOU "LACK[] FUNDAMENTAL PERSPECTIVE AND UNDERSTANDING OF HOW FUEL HEDGING WORKS IN THE INDUSTRY AND THE PURPOSE OF HEDGING PROGRAMS."[78] WHAT IS YOUR RESPONSE TO THIS?

A33. Mr. Snider is incorrect and here undermines his own testimony. I am well aware of the purpose and function of hedging, which Mr. Snider correctly identifies as "not [an] attempt to pick prices at given points in time,[but] to reduce annual volatility in fuel related costs

[78] Snider Rebuttal at 74.

consumers see in their bills."[79] The point of my testimony suggesting that the Company attempt to price a swap for a substantial fraction of its natural gas volume was to recommend this not as a fuel hedging strategy, but as a price discovery strategy.

Duke's stated usage of the small-volume swap purchases is contrary to how those swaps are actually utilized in the IRP. Mr. Snider states that Duke's small-volume swap purchases are used for both its hedging program (which is not intended to pick prices but to reduce price volatility) and to explore the indifference prices for PURPA QFs (to set prices for a relatively small fraction of the Company's purchase obligation).[80] He also notes that "any hedge has the potential to up or down in value[,] so concentrated large volume purchases at a single point in time can introduce unacceptable risk for customers."[81]

Mr. Snider's testimony conflicts with how the natural gas price forecast – based on the small-volume swap purchases – is actually being used by the Company as the basis for its projected fuel cost for <u>100%</u> of its natural gas generation over a 15-year period.[82] This is the modeling equivalent to a "large volume purchase at a single point in time," and it introduces unacceptable risk for customers by using a forecast based on values that are not reflective of the price to actually secure a comparable volume of natural gas.

The Company has claimed that its ability to purchase small volumes of natural gas swaps for ten years demonstrates a liquid market for those instruments.[83] It infers from

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[79] Snider Rebuttal at 74.
[80] Snider Rebuttal at 74-75.
[81] Snider Rebuttal at 74.
[82] While Duke utilized a basis differential for certain plants and included different transportation costs for peakers and combined cycle units, the underlying prices of the gas forecast was based on the swap purchase. Lucas Direct Exhibit KL-16.
[83] Snider Rebuttal at 74.

this that it is appropriate to price the *entire* natural gas supply in its IRP based exclusively on these market prices for ten years and indirectly on these market prices for an additional five years. That second assumption is wrong: it is simply not the case that the risk – and thus the expected price – of small-volume swaps is equivalent to the risk of large-volume swaps.

A swap is a contract between two parties. By purchasing a swap, Duke is purchasing the right to take physical delivery of a certain quantity of natural gas at a certain place for a certain price. The counterparty is obligated to physically deliver the natural gas to this location and will only receive the agreed-upon price for doing so. Counterparties to these swaps include financial institutions and banks whose primary business function is not producing or delivering gas; they will not have vast physical supplies of natural gas in a vault. Thus, while bank management might accept some degree of risk for small contracts that obligate the physical delivery of natural gas, the bank will ultimately have to cover its exposure through other financial instruments (e.g. NYMEX futures) or with other counterparties (such as a gas producer) to ensure that it does not have to purchase and physically deliver natural gas on the spot market at an arbitrarily high price to fulfill its swap obligation.

As the volume that the parties try to lock up over ten years increases, so does the risk to the counterparty obligated to deliver gas at the contract price. Duke's 2,500 MMBTU/day swap purchase that formed the basis of its market price forecast represented sufficient volume for only 0.088% of Duke's annual generation in 2020, and even less of its future forecast as its natural gas usage is projected to increase.[84] The current average price of a ten-year natural gas future is $2.65/MMBTU.[85] If one were to purchase a 10-year 2,500 MMBTU/day swap at this average price, the value of the contract would be nominally worth $24.2 million.[86] At the same price, locking in 10% of Duke's 2020 generation for ten years would require roughly 285,000 MMBTU/day, making that contract nominally worth $2.76 billion.[87] Finally, to lock in the cost of its full 2020 natural gas usage for ten years would require a swap for roughly 800,000 MMBTU/day, making that contract nominally worth a whopping $7.8 billion.[88]

For Duke to suggest that its ability to source a $24 million contract from multiple brokers for a given price means that it could source a $7.8 billion contract from multiple vendors for the same price is absurd. It is likely that no single counterparty would be willing to carry this much risk on its balance sheet, and if it were, it would price in a massive risk premium to do so. Duke's claim of a liquid market for small volume swaps, even if true, speaks nothing to the market liquidity or price premium for swaps of its entire natural gas supply. And yet, by incorporating the market prices of its small volume swaps into the IRP as the basis for entire natural gas market price forecast, it is directly and inappropriately translating the price of a fraction of its generation to the price of its entire generation.

[84] Preliminary 2020 annual generation from Duke Energy Progress and Duke Energy Carolina plants as reported in EIA Form 923 was 148,531,382 MWh. Calculation assumes an average heat rate of 7.0. Available at https://www.eia.gov/electricity/data/eia923/

[85] Average settlement price of May 2021 through April 2031 NYMEX NG future. Obtained 4/7/21 from https://www.cmegroup.com/ftp/settle/

[86] 2,500 MMBTU/day * 365 days * 10 years * $2.65/MMBTU = $24.181,250.

[87] 148,531,382 * 10% / 7.0 heat rate / 365 = 284,855 MMBTU/day.

[88] Natural gas usage of 294,309,454 MMBTUs * $2.65 * 10 years = $7,799,200,531.

Q34. MR. SNIDER CLAIMS THAT "MARK-TO-MARKET" RULES THAT REQUIRE VALUATION ON MARKET PRICES WHEN AVAILABLE UNDERCUT THE VIABILITY OF USING FUNDAMENTALS FORECASTS.[89] WHAT IS YOUR RESPONSE?

A34. Mr. Snider's statement is correct, but irrelevant to the issue at hand. The financial accounting rules of which he speaks relate to valuing of actual contractual obligations, not modeling results. These rules have nothing to do with how a particular natural gas forecast should be used in IRP modeling. In fact, the Company used a high and low gas price sensitivity that diverged from its claimed market prices as part of its IRP modeling. While I do not believe its methodology for constructing these sensitivities was sound,[90] Duke was correct to include different forecasts as part of its evaluation of its IRP portfolios. Mark-to-market rules could not possibly be construed as prohibiting or reducing the value of fuel price sensitivities in the IRP that were different from market prices, nor are they relevant to any natural gas price forecast used in the IRP.

Q35. MR. SNIDER CLAIMS THAT ARGUMENTS SIMILAR TO YOURS "HAVE BEEN RESOUNDINGLY REJECTED" IN OTHER DOCKETS.[91] WHAT IS YOUR RESPONSE TO THIS CLAIM?

A35. It is resoundingly false. The Company's natural gas price forecast methodology has been controversial and discussed in multiple dockets in both North Carolina and South Carolina, and the Company ignored for multiple years the NCUC's directive to develop a natural gas forecast that used at most eight years of market prices. Nothing in those dockets "resoundingly rejected" my analysis.

[89] Snider Rebuttal at 76.
[90] See e.g. Lucas Direct at 93-98.
[91] Snider Rebuttal at 78.

It is instructive to note that no party in the 2016 North Carolina avoided cost proceedings to which Mr. Snider alludes advocated for eight years of market prices as the NCUC determined. Rather, Duke was advocating for its current structure and NCUC Staff and other parties were recommending the use of market prices for no more than five years.[92] The NCUC noted that arguments made by all parties were compelling, questioning in particular the liquidity of the 10-year natural gas market, noting that "the number of such transactions is sufficiently fewer to prevent the Commission from relying completely on this method for establishing energy prices in this case[.]"[93] Ultimately, the NCUC found "merit in some of the arguments each party raises but determines for purposes of this case not to agree completely with any but, in the Commission's expert judgment, to adopt a method relying on market data for eight years and fundamental forecasts thereafter."[94]

This issue was relitigated in the 2018 North Carolina avoided cost proceeding. Again, the NCUC weighed the evidence and concluded:

> After careful consideration, the Commission is not persuaded that a change in the fuel forecasting methodology approved in the 2016 Sub 148 Order is appropriate, at this time. While the parties who have addressed this issue produced substantial, competent, and material evidence and well-articulated arguments in support of their positions, this evidence does not definitively support movement in either direction between fundamental forecasting and forward-market purchases.[95]

Far from being "resoundingly rejected," arguments similar to the ones I advance were sufficiently accepted by the NCUC to reject Duke's proposals to utilize market prices in its forecast for 15 years.

[92] 2016 Sub 148 Order at 77.
[93] 2016 Sub 148 Order at 77-78.
[94] 2016 Sub 148 Order at 77.
[95] 2018 Sub 158 Order at 59.

Q36. DO YOU BELIEVE THAT THE USE OF EIGHT YEARS OF MARKET PRICES IS THE RIGHT DURATION TO USE?

A36. I do not. The NCUC findings of fact called for a natural gas forecast that used "no more than" eight years of market prices.[96] As I discussed in detail in my direct testimony, I believe the maximum time permitted is still too long to rely on market prices that are based on illiquid futures contracts before transitioning to fundamentals-based forecasts. The points that Mr. Snider makes in rebuttal testimony are at times misleading (the totality of ORS's testimony on this point), irrelevant (financial account rules that do not apply to IRPs), or blatantly false ("resoundingly rejected"), while others actually support my positions (multiple fundamentals-based prices and small OTC purchases used for hedging purposes). If this Commission were to approve a natural gas forecast based on the shorter transition that I recommend, it would be fully consistent with the NCUC's findings.

I urge the Commission to recognize the critical role that the natural gas price forecast plays in this docket and how it can impact what is the most reasonable and prudent plan to meet the Company's future energy and capacity needs. Approving an IRP plan that contains more new natural gas generation than it would have if based on a more reasonable natural gas forecast will lead to unnecessary risk for the Company's customers.

V. SURREBUTTAL TESTIMONY ON OTHER MATTERS

A. Duke Should Include a PPA as a Resource Option

Q37. WHAT SOLAR RESOURCE OPTIONS DID DUKE INCLUDE IN ITS MODELING?

[96] 2016 Sub 148 Order at 77.

A37. Duke included only company-owned resources in its IRP, including a standalone solar resource and a solar plus storage resource. It did not include any solar PPA resources as ORS recommended and as DESC did in its IRP filing.

Q38. WHAT REASON DOES DUKE GIVE FOR EXCLUDING THIS RESOURCE?

A38. Its primary explanation is that modeling a 20-year PPA would create "an unequal and unfair comparison among generation resources" in the IRP model which is counter to the intent of Act 62.[97] The basis for this is two-fold. Mr. Snider notes the 20-year PPA duration as compared to the 30-year life of a company-owned solar system and raises concerns that the residual value of the PPA is unknown.[98]

Q39. WHAT IS YOUR RESPONSE TO THE CONCERN BETWEEN A 20-YEAR PPA AND A 30-YEAR PV SYSTEM?

A39. There is no reason that 20-year PPAs cannot be evaluated as a resource option. The Company is able to model resources with different lifetimes, and the model is able to select among them without issue. For instance, it assumes 35 years for natural gas units, 30 years for solar, 15 years for battery storage, and 80 years for existing nuclear facilities. Each resource has a characteristic set (e.g. heat rate, generation profile, outage rates, lifespans, etc.) and the model optimization is constrained by these values.

When a resource in the model retires, either due to economics or reaching end-of-life status, a new resource is selected to replace it. If a 20-year PPA were to end during the modeling period, the model would simply evaluate what, at that point in time, was the most economic replacement resource and select it. There is no need to set the duration of all

[97] Snider Rebuttal at 118.
[98] Snider Rebuttal at 119.

solar resources to 30 years any more than there is a need to set the lifetime of *all* resources to 30 years.

Q40. DUKE CLAIMS THAT IT MUST CALCULATE A RESIDUAL VALUE UNDER A HYPOTHETICAL CARBON PRICE TO ACCOUNT FOR THE "ASSOCIATED COST RISK" OF THE PPA-BASED PROJECT FROM YEARS 21-30. DOES THIS MAKE SENSE?

A40. No, it does not. First, the Company already includes PPAs in its build plan and assumes they will be replaced with "in-kind generation," which "could include renewal of existing contracts or replacement of existing contracts with new solar generation."[99] Duke makes no effort to calculate the hypothetical cost impact of these facilities in the post-PPA years.

Second, if Duke's assumption that future avoided costs will include a carbon price is correct, then avoided costs that include the carbon price would be appropriate. Avoided energy costs are based on the marginal resource, and under the Company's avoided cost methodology, the entire fleet is simulated on an hourly basis over ten years. After this simulation in completed, 100 MW of zero-cost energy is added in each hour and the simulation is run again. The difference between the two runs represents the marginal avoided energy costs. If a carbon price exists, then both runs will include it. Further, if a carbon price exists, then Duke's customers will already be paying it whether or not the PPA is renewed.

Finally, it is entirely speculative to assume that the current PURPA regime, with avoided costs based largely on marginal natural gas generation will still be in place 20 years from now. Given the list of changes that Mr. Snider recounts over the past several years, assuming that 20 years in the future Duke will continue to be a vertically integrated

[99] Exhibit KL-S-2, Duke Response to SCSBA's Second Request for Production to DEC/DEP ("SCSBA RFP 2") (producing Duke response to DR NCSEA 3-20).

monopoly operating outside of a competitive, regional wholesale market structure where QFs are treated as favorably as they are today (or more so) is highly speculative. It is highly unlikely that policy makers twenty-plus years from now will require utilities to pay $50 or more per megawatt hour for solar energy, as Duke suggests, if such energy can be produced and sold for half that price or less. Further, if the country continues to successfully decarbonize its electricity sector, then the marginal resource will likely be zero-carbon, zero-marginal price renewable resources or battery storage, not natural gas generation.

Q41. DOES DUKE HAVE ANY IMPLICIT BIAS TOWARDS COMPANY-OWNED PROJECTS AND AGAINST THIRD-PARTY PPAS?

A41. Yes, it does. Duke is a for-profit, investor-owned, monopoly utility, granted exclusive rights to serve customers in a geographic franchise territory. In exchange for this, Duke's prices are regulated by the Commission. Duke's franchise right carries an obligation to provide reliable and safe service based on reasonable and prudent investments, but Duke also has a fiduciary obligation to its investor owners to deliver profits. Without strong oversight by this Commission, Duke, as a monopoly provider of electricity service, would be positioned to exercise market power and earn unreasonable profits from its captive customers.

Duke earns profits through ownership of assets, such as company-owned solar projects. It does not earn profits on expenses, such as the purchase of power from third-party PPAs. This structural imbalance creates a clear preference for Duke to own its assets rather than purchase power from third-party providers. Duke's refusal to even include a 20-year PPA in its modeling based on flawed arguments is a product of this imbalance. At this point, solar PV is common in the Carolinas and Duke's customers should be pressing for the most cost-effective ownership structure to provide the energy and capacity from these projects. If the model demonstrates that third-party PPA purchases are more cost-effective than utility-owned projects, then they should be selected.

After all, the Company only has the opportunity – not an absolute right – to earn a reasonable return on its assets. And Duke certainly does not have the right to demand that it own all generation assets when purchasing power from third-party providers is a reasonable and prudent investment for Duke's customers. As long as South Carolina continues to choose to include generation in the list of allowed monopoly assets, this Commission must recognize this tension and its own obligation to protect Duke's customers from the exercising of market power by a for-profit monopoly entity.

B. Two-Hour Batteries Should be Considered as Part of the Solution.

Q42. PLEASE RECOUNT YOUR TESTIMONY RELATED TO TWO-HOUR BATTERIES.

A42. My direct testimony recommended that Duke include a limited quantity of two-hour batteries as part of its available resources in the model.[100] Duke at times appears to have misinterpreted my testimony to suggest that I recommend to use only two-hour batteries.[101] This is not the case. I was not advocating that these be the only available storage resource option and I included limits to reflect the diminishing capacity credits as more short duration batteries are added.

I recognize that two-hour batteries will serve a limited function in the Company's operations, but this limited function may prove to be a cost-effective strategy. If two-hour batteries were utilized to address the narrow peaks of winter mornings and evenings, longer

[100] Lucas Direct at 45.
[101] See e.g. Kalemba Rebuttal at 37 and Roberts Rebuttal at 30.

duration storage would be freed up to address the now-less-peaky remaining load. This mix of storage duration is shown in Figure 6 below, taken from an article summarizing an NREL report that investigated the ability of different storage durations to reduce peak demand.[102]

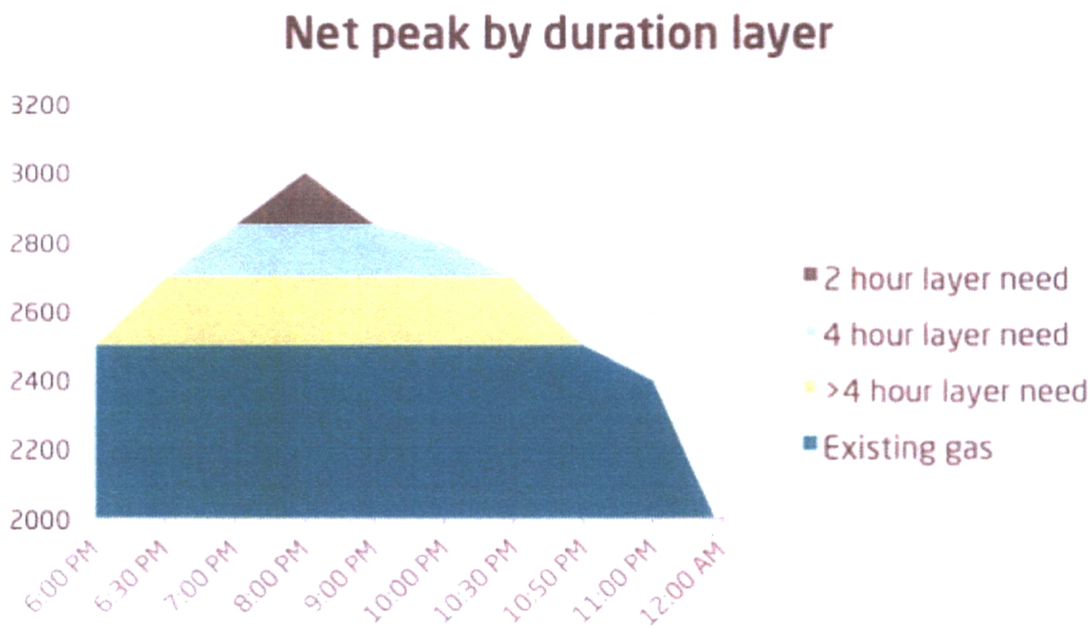

Figure 6 - Net Peak by Duration

Two-hour batteries can be complementary to the four- and six-hour batteries that the Company modeled, which are in turn complementary to the other resources that will be used to meet system demand and maintain reliability. If the modeling demonstrates the potential for these to be cost effective solutions, then they should be explored in more detail. But by completely excluding these resources from the model, Duke forgoes their potential.

[102] https://blog.fluenceenergy.com/meeting-peak-electricity-demand-with-energy-storage-duration-portfolio

C. *The Commission Should Adopt a Minimax Regret Analysis Across Portfolios.*

Q43. PLEASE REVIEW THE DIFFERENCES BETWEEN THE MINIMAX REGRET ANALYSIS YOU PERFORMED AND THE ONE PERFORMED BY ORS.

A43. The Minimax Regret analysis I performed calculated the max regret for each portfolio by comparing the highest cost of that portfolio in any fuel/CO_2 scenario to the lowest cost portfolio in any fuel/CO_2 scenario.[103] In this analysis, I found the Base Case with Carbon Policy as the lowest max regret of the combined DEC/DEP portfolio, followed by the Earliest Practicable Coal Retirement in second, and the Base Case without Carbon Policy in third.

By contrast, ORS calculated the max regret for each portfolio by comparing its cost to the lowest cost of a given fuel/CO_2 scenario.[104] After calculating the regret tab separately for DEC and DEP, ORS presents the max and mean regret, along with the regret standard deviation. It is unclear whether ORS's analysis uses Duke's PVRR figures with or without the explicit cost of carbon. I used the values with the cost of carbon included, arguing that scenarios which included a cost of carbon should be compared including these costs.

ORS finds that Base Plan with Carbon Policy has the lowest regret result for DEC (followed by the Earliest Practicable Coal Retirement and the Base Plan without Carbon Policy), while the Base Plan without Carbon Pricing has the lowest regret results for DEP (followed by the Base Plan with Carbon Policy and the Earliest Practicable Coal Retirement). Duke notes the differences between these methods and opines that it prefers the ORS methodology over my methodology, stating that "the approach outlined by

[103] Lucas Direct at 28.
[104] Direct Testimony of Lane Kollen, ORS, at 10.

Witness Kollen would be more applicable to scenario planning as only one future can happen, while several portfolios could be applied in that one scenario."[105]

Q44. PLEASE EXPAND ON THE DIFFERENCE BETWEEN YOUR AND ORS'S ANALYSIS.

A44. There are two structural differences in our approaches. First, ORS calculated the impact for DEC and DEP separately, while I combined the PVRRs of both portfolios. I believe the combined approach is more appropriate given the manner in which these factors will impact the Company. Clearly, whatever fuel and CO_2 policies are in place in the future will impact both operating companies similarly; one cannot imagine that somehow DEC would be subject to a carbon price while DEP would not or that only DEP plants would be subjected to high gas market prices. Similarly, it is unlikely that Duke would pursue the earliest practicable retirement of only its DEC coal plants and not its DEP coal plants if this is determined to be the optimal outcome.

The second difference is whether to limit the regret calculation to a given fuel/CO2 scenario or to compare the max regret across all scenarios. Here again, my approach is more appropriate. The analysis is called a "minimax regret" analysis, implying that one is seeking the single portfolio with the smallest maximum regret against all possible futures. While Mr. Snider claims that "only one future can happen," the entire point of scenario planning is to compare the potential outcome across multiple potential futures. In this case, the multiple potential futures are the various fuel/CO_2 combinations, not the various resource portfolios.

Essentially, ORS's analysis fixes a given fuel/CO_2 combination and then considers how it affects multiple portfolios. By contrast, my approach fixes a given portfolio and

[105] Snider Rebuttal at 145.

compares how it performs against multiple fuel/CO_2 combinations relative to the lowest cost combination. The future uncertainty is not what resource mix will be chosen, but rather what fuel/CO_2 combination will occur. Based on this, it is appropriate to define the "regret" as the incremental cost of a particular portfolio/fuel/CO_2 cost combination over the lowest cost portfolio under the lowest cost case. This is how I performed my analysis.

Q45. IS THERE ANYTHING ELSE ON THIS TOPIC YOU WOULD LIKE TO DISCUSS?

A45. Yes. I criticized Duke's overall lack of risk assessment in its IRP filing. The minimax regret analysis is a simple, yet useful, method to provide some insight on the performance of different resource mixes under uncertainty. However, these analyses are necessarily dependent on the accuracy of Duke's modeling. I have already discussed my issues with their central natural gas forecast, and also found methodological issues with Duke's construction of its high and low fuel cost sensitivities. These variables of course will impact the PVRR upon which the regret analysis is based.

As shown in the Synapse modeling, with some reasonable changes in assumptions, a portfolio with no new natural gas and a different renewable buildout can be found that costs substantially less than Duke's base cases while still meeting all energy and capacity needs. While Synapse did not perform multiple sensitivities on fuel and CO_2 costs, its modeling shows the importance of having a solid modeling baseline on which to conduct additional analyses.

D. The Commission Should be Skeptical of Duke's Energy Storage Costs and Require Single-Axis Tracking for the Modeling of all Future Solar Facilities.

Q46. PLEASE REVIEW YOUR DIRECT TESTIMONY ON DUKE'S ENERGY STORAGE COSTS.

A46. I found several issues with Duke's energy storage cost assumptions. This included inflated costs compared to other metrics, largely due to unreasonable depth of discharge and degradation assumptions. I also found a calculation error in Duke's formula for battery replenishment in its solar plus storage systems, and noted inconsistency between costs used for standalone and solar plus storage systems.[106]

Q47. DID ONE OF YOUR POINTS CONTAIN AN ERROR?

A47. Yes. I had asserted that the battery pack assumptions that Duke used for its standalone storage and solar plus storage systems were different. This was based on a miscalculation that did not incorporate Duke's large depth of discharge overbuild assumptions. When accounted for, the battery pack costs are the same in both versions.

Q48. ASIDE FROM THIS ERROR, DO YOU STAND BY YOUR DIRECT TESTIMONY?

A48. Yes. Duke's storage costs are too high, and the reasons that the Company provided in rebuttal testimony on this issue do not close the gap.

Q49. WHAT WAS DUKE'S BASELINE COST ESTIMATE FOR A FOUR-HOUR BATTERY COMPARED TO THE LATEST COST ESTIMATE FROM NREL?

A49. Duke's baseline 2020 cost estimate was $[redacted] for a [redacted] MW/[redacted] MWh battery, resulting in a cost of $[redacted]/MWh.[107] The 2019 NREL benchmark price was $380/MWh,[108] and the recently-updated 2020 NREL benchmark price has fallen to $341/MWh for a 60 MW/240 MWh battery.[109] Duke's 2020 cost is nearly [redacted]% higher than NREL's benchmark on a per MWh basis.

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[106] Lucas Direct at 39.
[107] PSDR 3-7 Confidential - IRP Generic Unit Summary DEC 2020.
[108] Cost Projections for Utility-Scale Battery Storage: 2020 Update, NREL. Available at https://www.nrel.gov/docs/fy20osti/75385.pdf
[109] U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020, NREL. Available at https://www.nrel.gov/docs/fy21osti/77324.pdf

Q50. DUKE CONTINUES TO CLAIM THAT ITS BATTERY COST IS REASONABLE. WHAT IS ITS POSITION BASED ON?

A50. Duke claims that the cost estimates from other sources do not properly include depth of discharge and degradation factors, are priced based on brownfield siting and no interconnection costs, and use lower quality software and control systems.[110]

Q51. DOES DUKE PROVIDE ANY SUPPORT FOR THESE ASSERTIONS?

A51. None that holds up to scrutiny. Mr. Kalemba states that "some published resources may not properly include the cost impacts of Depth of Discharge (DoD) limitations that are required of some battery technologies to meet manufacturer warranty requirements."[111] While this may be true for some published data, as I discussed in my direct testimony, NREL's cost estimates account for degradation through its fixed O&M cost, while Lazard's latest cost estimates also accounted for depth of discharge and degradation.[112]

Duke also claims "[i]t is likely that at least some of the published battery costs meet the Companies' requirements, however it is likely that many of the published battery costs would not be robust enough to meet the needs of the Companies' system and some may not even meet the basic requirements to interconnect to the system."[113] The Company provides no support for this bold assertion and I recommend the Commission discount it entirely given its complete lack of foundation. Duke's assertion that it knows, despite admitting to a lack of experience integrating batteries into its grid, that it must spend

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[110] Kalemba Rebuttal at 17.
[111] Kalemba Rebuttal at 16.
[112] Lucas Direct at 42: "By contrast, NREL allocates all operating costs to the fixed O&M bucket and uses the higher of the fixed O&M estimates from third parties, thus 'in essence assum[ing] that battery performance has been guaranteed over the lifetime, such that operating the battery does not incur any costs to the battery operator.'" (internal citations omitted).
[113] Kalemba Rebuttal at 16.

substantially more money just to procure a "robust enough" battery while providing no support for this decision is the definition of utility "gold-plating."

The Company claims that it assumes batteries will be installed in greenfield locations that require additional siting and interconnection costs but provides no justification for this incremental expense. Battery systems have a relatively small footprint and it may be possible for Duke to accommodate storage at or near existing generation sites. Assuming every system will require greenfield development along with new transmission and/or distribution interconnections is an extremely conservative position. While this may be required for some storage, it should not be accepted as the baseline consideration for every battery.

Q52. DUKE CLAIMS THAT YOU "CHERRY PICKED" DATA TO SUPPORT LOWER STORAGE PRICES. HOW DO YOU RESPOND TO THIS?

A52. Far from cherry picking the data, I simply reported the prices provided by the sources Duke had already reviewed. When I asked the Company to provide all publicly available sources that it reviewed when detailing its battery cost assumptions, Duke provided three sources: NREL ATB, Lazard, and PNNL/DOE.[114] My table contains data from NREL ATB, Lazard (2019 and 2020 versions), and the Santee Cooper RFI.[115]

For completeness, the 2019 PNNL/DOE report Duke referenced contains a cost of $1,806/kW or $469/kWh in 2018 for lithium-ion battery storage.[116] It also utilizes the same 80% DoD figure and nearly identical round-trip efficiency (86% for PNNL/DOE vs. 85% for

[114] Exhibit KL-7, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-14, attachment NCSEA DR 3-14_BatteryCostComparison).
[115] Lucas Direct at 40.
[116] Storage Cost and Performance Characterization Report, PNNL/DOE. Available at https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

Duke).[117] NREL's 2020 ATB Advanced found storage capital costs falling 22.7% after inflation between 2018 and 2020.[118] Applying this factor would convert the 2018 PNNL/DOE figure to $362/MWh in 2020. This is squarely in line with the latest NREL 2020 figure of $341/MWh, and is yet another data point that is substantially below Duke's estimate, despite PNNL/DOE assuming power control systems and balance of plant costs of 20% of the total, as compared to 13% of the total for Duke.

Q53. WHAT DO YOU RECOMMEND WITH REGARD TO THE BATTERY COSTS?

A53. I continue to recommend for this case that the Commission direct Duke to utilize the NREL ATB Low figures. This is consistent with its directive in the DESC Order. I also recommend that Commission order Duke to issue an RFI for battery storage projects to provide better pricing information for the next IRP Update and future IRPs. This RFI should include reasonable HVAC, fire suppression, and control software that is consistent with best practices in the utility industry. It is clear from both Duke's and Synapse's modeling that battery storage will be an increasingly important resource going forward and having locally-accurate pricing will be very useful for future modeling efforts.

Q54. DID DUKE COMMIT TO CHANGE ITS ASSUMPTIONS REGARDING THE MIX OF SINGLE-AXIS TRACKING SYSTEMS AND FIXED-TILT SYSTEMS IN THE FUTURE?

A54. Yes, it did. Duke committed to shifting to 100% SAT systems for all new modeled Tranche 2 CPRE projects and economically selected solar.[119] This matches my recommendation and I agree with Duke's proposed change. However, Duke only indicated that it is "evaluating modeling all future solar + storage projects as 100% tracking."[120] It is entirely

[117] Exhibit KL-S-5, NCSEA 3-14.
[118] https://atb.nrel.gov/
[119] Kalemba Rebuttal at 33.
[120] Kalemba Rebuttal at 33.

unclear why the Company will not also commit to modeling solar plus storage systems as 100% SAT as well, particularly given that these systems have even more incentives to maximize generation to fully charge the batteries. I recommend that the Commission require Duke to assume for modeling purposes that 100% of all new solar projects, including solar plus storage projects, are SAT systems.

Q55. DUKE CONTINUES TO CONTEND THAT IT IS REASONABLE FOR PURPA PROJECTS TO CONTINUE TO BE MODELED AS FIXED-TILT.[121] DO YOU AGREE WITH THIS?

A55. No. In my direct testimony, I showed that even smaller systems that are more likely to go the QF route have been transitioning to SAT, with nearly all of the sub-5 MW projects tracked by DOE having shifted to SAT by 2019. As such, it is unlikely that all PURPA projects are currently fixed-tilt. Duke should determine the actual system mix for its existing PURPA projects and use that as the baseline for the fixed-tilt assumptions for existing projects that are assumed to be renewed. However, for any future PURPA QF projects that Duke assumes will be added, it should reflect the recent trends and shift to more SAT. I continue to recommend that at least 80% of all new QF projects be modeled as SAT based on the analysis in my direct testimony.[122]

VI. CONCLUSIONS AND RECOMMENDATIONS

Q56. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A56. As stated in my direct testimony, Duke's IRP does not conform with the requirements of Act 62 and must be rejected.[123] The Company should incorporate numerous updates to its modeling that I discussed, including the incorporation of current law related to the ITC

[121] Kalemba Rebuttal at 32.
[122] Lucas Direct at 54.
[123] Lucas Direct at 9.

extension and a more reasonable natural gas forecast. It should also produce a more robust risk assessment of its portfolios, with particularly attention to the financial and regulatory risk associated with large new natural gas buildouts.

As discussed above, Duke has failed to rebut these conclusions, which are further supported by the modeling conducted by Synapse and further explained in witness Rachel Wilson's surrebuttal testimony.

Q57. WHAT ACTIONS DO YOU RECOMMEND THE COMMISSION TAKE WITH REGARD TO DUKE'S IRP IN THIS DOCKET?

A57. I have several recommendations for the Commission, as discussed above. First and most importantly, the Commission should address the significant deficiencies in Duke's IRP by rejecting or modifying the IRP under consideration in *this* docket. It should not allow Duke to defer changes necessary to comply with Act 62 until the 2021 IRP Update or even the next "full" IRP.

Second, I recommend that the Commission reject Duke's IRP, and direct Duke to file a revised IRP in this docket, with the following modifications:

- Duke must update its modeling with more the reasonable assumptions recommended in my Direct and Surrebuttal Testimony. Specifically, the updated modeling should reflect:
  - The extension of the federal ITC;
  - Battery costs based on NREL ATB Low;
  - Solar fixed O&M costs based on a comparable discount from NREL ATB as capital costs;

   - 100% SAT for all future non-QF projects and at least 80% SAT for all future QF projects;
   - Two-hour batteries and 20-year solar PPAs as eligible resources;
   - Natural gas forecast based on the methodology recommended in my direct testimony;[124] and
   - Incorporate the Synapse interconnection limitations for renewable generation and batteries that can be interconnected on an annual basis.
- Duke should also model and conduct sensitivity analyses on an additional scenario, reflective of the modeling changes I recommend as well as the following modified assumptions, based on of the "Reasonable Assumptions" scenario described in the Synapse Report and Ms. Wilson's testimony:
   - Increase the forecasted energy efficiency in Duke's service territories such that first year program savings starts to increase from 2022 by 0.15 percent of retail sales per year until they reach 1.5 percent, and then stay at this level through the study period.
   - Use Duke's "Earliest Practicable" retirement timeline and pathway for coal-fired units.
   - Correct the costs for the wind resource options offered to the model for replacement capacity and energy, utilizing values from the NREL's 2020 ATB.

[124] This methodology would average a month's worth of NYMEX daily closing futures prices to construct the market price portion of the forecast. These market prices would be used for 18 months before transitioning over 18 months to the average of at least two fundamentals-based forecasts. After 36 months, the average of the fundamentals-based forecast would be utilized.

- Levelize the costs of wind and solar resources using Duke's financing assumptions on weighted average cost of capital and construction schedule for the different resources, provided to the model on a $/MWh basis; and
- Restrict new gas additions.

- Duke should be required to state clearly whether it believes one of its six scenarios represents the most reasonable and prudent resource plan or, if it is unwilling to do so, to acknowledge that it will accept the Commission's decision on that issue.
  - If it does select a single most reasonable and prudent plan, it must include in its action plan the short-term measures it will take to implement that plan.

Only when the Commission has the results of this modeling can it determine the most reasonable and prudent plan to meet Duke's energy and capacity needs. In anticipation of modeling results that are similar to Synapse, the Commission should also direct Duke to immediately begin an RFP process for standalone solar, standalone storage, and solar plus storage projects in comparable levels to the schedule shown in Figure 3 and detailed in Exhibit KL-S-3, Synapse Solar PV and Battery Build Schedule.. Advancing the timeline of these procurements will enable greater capture of the federal ITC extension and smooth out the large quantities of resources that will need to be interconnected over the coming decade.

The Commission should also require Duke to utilize the Minimax Regret methodology I discussed in my direct testimony. I also recommend the Commission require Duke to produce a more robust risk analysis in future filings, including a detailed assessment of the fuel supply, fuel cost, regulatory, and financial risk associated with any future natural gas builds.

If the Commission elects to make its decision about the most reasonable and prudent plan on the current record, for the reasons stated in my testimony the Base Case without Carbon portfolio is the most reasonable and prudent plan.

Q58. DOES THIS CONCLUDE YOUR TESTIMONY?

A58. Yes, it does.